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An Assessment of the Potential for Energy Savings in Dry Mill Ethanol Plants from the Use of Combined Heat and Power (CHP)

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Executive Summary

Fuel ethanol is one of the fastest growing segments of the U.S. chemical industry. In 2005 the industry's ninety operating plants produced almost 4 billion gallons of ethanol. Provisions in the Energy Policy Act of 2005 are expected to drive industry expansion even further, providing a market for nearly 8 billion gallons of ethanol by 2012. The industry is poised to invest an estimated $6 billion in new plants and expansions to build the required capacity to meet this market demand.

One of the more controversial issues related to expanded use of fuel ethanol is the question of the "net energy balance" of the total ethanol production process; i.e., is more energy used to grow, transport and process the raw material into ethanol than is contained in the ethanol itself? Numerous researchers have studied this question and, based on the most recent results, a consensus is growing that the production of ethanol is indeed a positive net energy generator. Today's higher corn yields, lower energy use per unit of output in the fertilizer industry, and advances in ethanol process technologies have greatly improved the energy efficiency of producing dry corn mill ethanol (the primary production path for fuel ethanol) compared with just a decade ago[1,2].

Driven by rising energy prices and the fact that energy costs are second only to raw material costs in the dry mill ethanol industry, the industry has continued to improve its energy efficiency profile. Further efficiencies in the ethanol production process have been documented, and the industry has expanded its fuel options as well; where almost all of the dry mill plants were natural gas based five years ago, there are a number of plants now under construction based on coal and biomass fuels.

Along with increased production efficiencies and expanded fuel capabilities, combined heat and power (CHP) is increasingly being considered as a main stream option by many owner and financing groups[3]. The efficiencies of CHP can further improve the net energy balance of dry mill ethanol plants, but the level of improvement has been unclear. This paper summarizes an analysis of state of the art natural gas- and coal-based dry mill ethanol plants, comparing energy consumption of the ethanol production process with and without CHP systems. Only the energy consumption in the dry mill conversion process itself was evaluated; the analysis did not consider the energy consumption in growing, harvesting and transporting the feedstock corn or in transporting the ethanol product itself.

Table 1 summarizes the results of the analysis based on the energy consumption patterns of new natural gas and coal dry mill ethanol plants producing 50 million gallons of fuel ethanol per year. As shown in the table, while CHP increases the consumption of fuel at the plant itself, it reduces the amount of electricity purchased from the grid. Total fuel consumption for producing ethanol – considering both fuel use at the ethanol plant and fuel use at the central station power generation plant - is reduced with the use of CHP. Reductions in total fuel use are over 12% in the natural gas case and 10% in the coal case.

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[1] Researchers at Argonne National Laboratory estimate that, based on farming and ethanol production practices of 2001, 0.75 Btu of fuel was consumed to generate 1.0 Btu of dry corn mill ethanol (including fuel used in fertilizer production, farming, transport of corn to the mill, the ethanol production process, and transport of ethanol to market - Michael Wang, "Energy and Greenhouse Gas Emissions Results of Fuel Ethanol", presentation to the Governors' Ethanol Coalition, Kansas City, KS, February 2006.

[2] Hosein Shapouri, James Duffield, Michael Wang, "The Energy Balance of Corn Ethanol: An Update", USDA Agricultural Economic Report Number 813, July 2002.

[3] Combined heat and power (CHP) systems produce both electricity and thermal energy from a single fuel at or near the consumer. These efficient systems recover heat that normally would be wasted in the generation of electricity, and save the fuel that would otherwise be used to produce heat or steam for the site.

Figure 1 – Summary of Energy Consumption in the Dry Mill Ethanol Process – With and Without CHP

	Natural Gas - no CHP	Natural Gas - w/CHP	Coal - no CHP	Coal - w/CHP
Nominal Capacity, MMGal/yr	50	50	50	50
Ethanol Yield, Gallons/bushel	2.8	2.8	2.8	2.8
Electric Consumption, kWh/Gal	0.75	0.75	0.87	0.87
Annual Electric Consumption, kWh	37,500,000	37,500,000	43,500,000	43,500,000
Average Electric Demand, MW	4.4	4.4	5.1	5.1
CHP System	None	Gas Turbine w/Fired HRSG	None	Boiler/Steam Turbine
CHP Capacity, MW	0	4.0	0	4.8
Purchased Electricity, MWh	37,500	4,850	43,500	39,415
Generated Electricity, MWH	0	32,650	0	4,085
Plant Fuel Consumption, MMBtu/yr	1,616,500	1,735,769	2,012,821	2,203,861
Plant Fuel Consumption, Btu/Gal Ethanol	32,330	34,715	40,256	44,077
Central Station Fuel Use, MMBtu/yr	419,156	54,216	486,231	45,664
Total Fuel Use (Plant and Central Station), MMBtu/yr	*2,035,656*	*1,789,985*	*2,499,052*	*2,249,525*
Reduction in Total Fuel Use with CHP, %		*12.1%*		*10.0%*

Baseline Energy Consumption Profiles for Dry Mill Corn Ethanol Production Facilities

Dry mill ethanol is the fastest growing market segment in the industry and is comprised of dedicated ethanol facilities producing 20 to 150 million gallons per year. Energy is the second largest cost of production for dry mill ethanol plants, surpassed only by the cost of the corn itself. Dry mill plants use significant amounts of steam for mash cooking, distillation and evaporation. Steam or natural gas is also used for drying by-product solids (dried distilled grains solids or DDGS). Electricity is used for process motors, grain preparation, and a variety of plant loads. A typical 50 million gal/year dry mill plant will have steam loads of 100,000 to 150,000 lbs/hr and power demands of 4 to 6 MW depending on its vintage and mix of operations. The industry is expected to consume 250 to 290 trillion Btus of fuel and 7.5 to 8.5 billion kWh of electricity annually by 2012.

Table 2 provides energy consumption estimates (natural gas- and coal-based) for a 50 million gallon per year state-of-the-art dry mill ethanol plant based on information from engineering and energy suppliers. The estimates reflect expected energy performance of new ethanol plants installed in 2006. The assumptions in Table 1 are based on ethanol production only (e.g., no CO2 recovery) and 100% drying of the wet cake for cattle feed product (DDGS).

The natural gas values are based on multiple packaged natural gas boilers generating steam for the process. Natural gas is also used directly in the DDGS dryer, and in the regenerative thermal oxidizer that destroys the VOCs present in the dryer exhaust. The coal system estimates are based on a fluidized bed boiler system that integrates exhaust from a steam heated DDGS dryer as combustion air to the boiler; in this case, VOC destruction occurs in the boiler itself and there is no need for a separate thermal oxidizer. The per gallon electricity consumption is higher for the coal system (0.87 kWh/gal versus 0.75 kWh/gal for natural gas) due to an estimated 15 to 20% additional power requirements for fuel handling and processing[4]. The total steam consumption per gallon of ethanol is higher for the coal system as well,

[4] For comparison, the USDA economic report (reference 2) used an average electricity consumption of 1.09 kWh/gal for 2001.

reflecting the use of a steam DDGS dryer instead of a fuel-fired system. There is no direct fuel consumption for either a DDGS dryer or a thermal oxidizer in the coal-based system.

Table 2 – Energy Consumption Assumptions for State-of-the-Art Dry Mill Ethanol Plants – 2006[5]

	Natural Gas-Based Plant	Coal-Based Plant	References
Nominal Capacity, MMGal/yr	50	50	
Ethanol Yield, Gallons/bushel	2.8	2.8	1
Electric Consumption, kWh/Gal	0.75	0.87	Natural Gas: 1, 2; Coal: 2, 4
Annual Electric Consumption, kWh	37,500,000	43,500,000	Calculated
Boiler Type	Packaged	Fluidized Bed	1, 2, 4
Boiler Efficiency, HHV	80%	78%	5
Boiler Fuel Consumption for Process Steam, Btu/Gal	21,500	22,050	Natural Gas: 1, 2, 3, 4; Coal: 2, 4
Annual Process Steam Consumption, MMBtu	860,000	860,000	Calculated
Fuel Consumption for DDGS Dryer, Btu/Gal	10,500	N/A	1, 2, 3, 4
Steam Consumption for DDGS Dryer, Btu/Gal	N/A	14,200	4
Annual Fuel Consumption for DDGS Dryer, MMBtu	525,000	N/A	Calculated
Annual Steam Consumption for DDGS Dryer, MMBtu	N/A	710,000	Calculated
Fuel Consumption for Thermal Oxidizer, Btu/Gal	330	N/A	4, 5
Total Annual Fuel Consumption for Thermal Oxidizer, MMBtu	16,500	N/A	Calculated
Total Annual Steam Consumption, MMBtu	860,000	1,570,000	Calculated
Total Annual Boiler Fuel Consumption, MMBtu	1,075,000	2,012,821	Calculated
Total Annual Fuel Consumption, MMBtu	1,616,500	2,012,821	Calculated
Total Fuel Consumption, Btu/Gal	32,330	40,256	

References:

1. "Dry Mill Ethanol Plants", Bill Roddy, ICM, Governors' Ethanol Coalition, Kansas City, Kansas, February 10, 2006
2. Personal Communications with Matt Haakenstad, U.S. Energy Services
3. "Thermal Requirements: Coal vs. Natural Gas", Casey Whelan, U.S. Energy Services, Fuel Ethanol Workshop, Milwaukee, Wisconsin, June 20, 2006
4. Personal communications with Steffan Mueller, University of Illinois at Chicago; data from Henneman Engineering
5. Energy and Environmental Analysis, Inc estimates

The Impact of CHP on Energy Consumption Profiles

Based on the energy consumption assumptions outlined above, an analysis was conducted of the relative energy consumption of dry mill ethanol plants incorporating CHP compared to conventional non-CHP boiler plant designs. The analysis was based on state-of-the-art 50 million gallons/year natural gas- and coal-based ethanol plants described above. Two base case plant designs were considered:

- Natural Gas Base Case - Conventional (non-CHP) natural gas boiler, gas-fired DDGS dryer, and regenerative thermal oxidizer.

- Coal Base Case - Non-CHP fluidized-bed coal boiler with exhaust from a steam-heated DDGS dryer integrated into the boiler intake for VOC control.

[5] "State of the Art" reflects the energy performance of new dry mill ethanol plants in 2006

Both base cases were assumed to operate 24 hours per day, seven days a week, for 51 weeks a year (8592 hours). Table 3 presents the hourly steam and electric demands of the two base cases based on the energy consumption assumptions outlined in Table 1. Steam consumption is based on delivering 150 psig saturated steam to the process (energy input from the boiler of 1,022 Btu per pound of steam).

Table 3 –Steam and Electric Demands for 50 Million Gallon per Year Dry Mill Ethanol Plants

	Natural Gas Base Case	Coal Base Case
Nominal Capacity MMGal/yr	50	50
Annual Operating Hours	8592	8592
Electric Consumption, kWh/Gal	0.75	0.87
Annual Electric Consumption, kWh	37,500,000	43,500,000
Average Electric Demand, MW	4.4	5.1
Total Annual Steam Consumption, MMBtu	860,000	1,570,000
Hourly Steam Consumption, MMBtu/hr	100.1	182.7
Hourly Steam Consumption, lbs/hr	97,938	178,795

Two CHP plant designs were evaluated:

- Natural Gas CHP - Gas Turbine CHP with a supplementary-fired heat recovery steam generator (HRSG), natural gas-fired DDGS dryer, and a natural gas-fired regenerative thermal oxidizer.

- Coal CHP - High pressure fluidized-bed coal boiler with steam turbine generator, with exhaust from steam-heated DDGS dryer integrated into the boiler intake for combustion air and VOC destruction.

Table 4 provides the CHP system descriptions and performance characteristics assumed for the analysis.

Table 4 – CHP System Description

	Natural Gas CHP	Coal CHP
CHP System	Gas Turbine/HRSG	Boiler/Steam Turbine
Net Electric Capacity, MW	4.0	4.8
System Availability, %	95%	95%
Annual Operating Hours (8592 hours x 95%)	8,162	8,162
Annual Electricity Generated, kWhs	32,650,000	39,415,000

There are currently four gas turbine CHP systems similar to the system described in this paper operating at dry mill ethanol plants in the United States[6]. The gas turbine system considered in this analysis was sized to ensure that all generated power would be used on-site (the CHP system capacity was limited to 90% of the average plant electric demand). Gas turbine performance was based on a Solar Turbines Centaur 50. Since a 4.0 MW gas turbine will not produce enough steam in an unfired HRSG to meet the plant steam requirements outlined in Table 2 (only about 20% of the plant's 100.1 MMBtu/hr steam demand can be supplied with the turbine exhaust itself), supplementary firing was incorporated into the design. Steam generation efficiency for the supplemental burner was assumed to be 90%.

[6] Gas turbine CHP systems are installed at Adkins Energy LLC, Lena, IL; U.S. Energy Partners, Russell, KS; Northeast Missouri Grain, Macon, MO; and Otter Creek Ethanol, Ashton, IA.

The first coal based dry mill ethanol plants are just coming on line in 2006. At least one includes a steam turbine CHP system similar to the system described in this analysis[7]. The size of the coal-based steam turbine system is set by the steam demand of the plant. The CHP system analyzed consists of an 180,000 pound per hour fluidized bed boiler producing steam at pressures and temperatures higher than the process requirements (650 psig and 600 F). The entire steam output of the boiler enters a back pressure steam turbine where 4.8 MW of electricity is generated before the steam exits the turbine at the 150 psig pressure required for the process. The capacity of the steam turbine generator is approximately 94% of the average plant power demand, ensuring that all generated power can be used on-site.

Table 5 provides detailed performance and output characteristics of the gas turbine based CHP system and compares purchased electricity use and fuel use with the base case non-CHP natural gas ethanol plant. Based on the system performance assumptions outlined above, the gas turbine CHP system produces about 87% of the plant's total annual electricity needs and 95% of the plant's steam needs. While the CHP system displaces 1,021,250 MMBtu/yr of natural gas in the boiler, it consumes 414,128 MMBtu/yr in the gas turbine and an additional 726,931 MMBtu/yr in the HRSG supplemental burner. Overall natural gas use at the plant increases from 1,616,500 MMBtu/yr in the non-CHP base case to 1,735,769 MMBtu/yr with CHP. Process fuel consumption per gallon of ethanol product increases from 32,330 Btu/gallon to 34,715 Btu/gallon. However, the CHP system displaces 32,650 MWh/yr of purchased electricity. Assuming an average central station generating efficiency of 33% and average transmission and distribution system losses of 7.5% (resulting in a net central station generating efficiency of 30.5%), the CHP system displaces 364,950 Btu/yr of central station generation fuel. When central station fuel consumption is added to the ethanol plant fuel consumption, total fuel use (fuel consumed at the ethanol plant and at the central power plant) is reduced with the CHP system by over 12% (2,035,665 MMBtu/yr for the non-CHP base case versus 1,789,986 MMBtu/yr for the gas turbine CHP system).

Table 6 provides detailed performance and output characteristics of the coal boiler/steam turbine based CHP system and compares purchased electricity use and fuel use with the base case non-CHP coal ethanol plant. Based on the system performance assumptions outlined above and in Table 5, the steam turbine CHP system produces about 91% of the plant's total annual electricity needs. The CHP system uses about 9.5% additional coal over the base case in order to provide higher pressure and temperature steam for the turbine generator. Overall coal use at the plant increases from 2,012,821 MMBtu/yr in the non-CHP base case to 2,203,861 MMBtu/yr with CHP. Process fuel consumption per gallon of product increases from 40,256 Btu/gallon to 44,077 Btu/gallon. However, the CHP system displaces 39,415 MWh/yr of purchased electricity. Again assuming overall average central station delivered efficiency of 30.5%, the CHP system displaces 440,567 Btu/yr of central station generation fuel. When central station fuel consumption is added to the ethanol plant fuel consumption, total fuel use is reduced by 10% with the CHP system (2,499,051 MMBtu/yr for the non-CHP base case versus 2,249,525 MMBtu/yr for the steam turbine CHP system).

[7] Central Illinois Energy, Canton, IL – a 37 MMGal/yr plant fueled by coal fines and coal; incorporates a fluidized bed boiler/steam turbine CHP system.

Table 5 – Energy Comparison of Natural Gas-Based Ethanol Plant – With and Without CHP

	Natural Gas Base Case Gas Boiler wo/CHP	Natural Gas CHP Gas Turbine CHP with Fired HRSG
Plant Data		
Plant Capacity, MMgal/yr	50	50
Annual Plant Shutdown, Days	7	7
Operating Hours	8592	8592
Electric Use, kWh/gal	0.75	0.75
Electric Use, MWh/yr	37,500	37,500
Average Electric Demand, MW	4.4	4.4
Total Steam Demand, lb/hr (based on 21,500 boiler fuel use/gal)	97,938	97,938
Total Steam Demand, lb/yr	841,487,280	841,487,280
Steam Temperature, F	365	365
Steam Pressure, psig	150	150
Steam Enthalpy, Btu/lb	1,197	1,197
Steam Energy Gain in Boiler, Btu/lb (175 Btu/lb condensate return)	1,022	1,022
Boiler Efficiency, %	80.0%	80.0%
Boiler Fuel, MMBtu/yr (21,500 Btu/gal)	1,075,000	53,750
Boiler Steam Output, MMBtu/yr	860,000	43,000
Boiler Steam Output, MMBtu/hr	100.1	100.1
Dryer Fuel, MMBtu/yr (10,500 Btu/Gal - 100% DDGS)	525,000	525,000
Oxidizer Type	Regenerative	Regenerative
Thermal Oxidizer Fuel, MMBtu/yr (330 Btu/gal)	16,500	16,500
Gas Turbine Electric Capacity, MW	-	4.0
CHP Net Electric Efficiency, %	-	26.9%
CHP System Availability, %	-	95%
CHP Operating Hours	-	8,162
Gas Turbine Fuel Input, MMBtu/hr	0	50.7
Gas Turbine Fuel Input, MMBtu/yr	0	414,128
HRSG Burner Efficiency, %	-	90.0%
HRSG Fuel Input, MMBtu/hr	0	89.0
HRSG Fuel Input, MMBtu/yr	0	726,391
Unfired CHP Steam Output, MMBtu/hr	0	20.0
Total CHP Steam Output, MMBtu/hr	0	100.1
Total CHP Steam Output, MMBtu/yr	0	817,000
CHP Power Generated, MWh/yr	0	32,650
Purchased Power, MWh/yr	37,500	4,850
Total Plant Fuel Use, MMBtu/yr	1,616,500	1,735,769
Btu Plant Fuel/Gal Ethanol	32,330	34,715
Average Central Station Generation Efficiency - Delivered, %	30.5%	30.5%
Central Station Fuel Use, Mbtu/yr	419,165	54,216
Total Fuel Use (Plant and Central Station), MMBtu/yr	2,035,665	1,789,986

Table 6 – Energy Comparison of Coal-Based Ethanol Plant – With and Without CHP

	Coal Base Case Coal Boiler wo/CHP w/Integral VOC and Steam Dryer	Coal CHP Case Coal Boiler w/CHP w/Integral VOC and Steam Dryer
Plant Data		
Plant Capacity, MMgal/yr	50	50
Annual Plant Shutdown, Days	7	7
Operating Hours	8592	8592
Electric Use, (0.75 kWh/Gal + 15% parasitic)	0.87	0.87
Electric Use, MWh/yr	43,500	43,500
Electric Demand, MW	5.1	5.1
Steam Use, lbs/hr - Process	97,938	97,938
Steam use, lbs/hr - Dryer (based on 14,200 Btu/Gal)	80,856	80,856
Steam Use, lbs/yr	1,536,203,523	1,536,203,523
Steam Temperature, F	365	600
Steam Pressure, psig	150	650
Steam Enthalpy, Btu/lb	1,197	1,294
Steam Energy Gain in Boiler, Btu/lb	1,022	1,119
Boiler Efficiency, %	78.0%	78.0%
Boiler Fuel, MMBtu/yr	2,012,821	2,203,861
Steam Output, MMBtu/yr	1,570,000	1,719,012
Steam Output, MMBtu/hr	182.7	200.1
Dryer Fuel, MMBtu/yr	0	0
Oxidizer Type	None	None
Thermal Oxidizer Fuel, MMBtu/yr	0	0
Steam Turbine Electric Capacity, MW	-	4.8
CHP System Availability, %	-	95%
CHP Operating Hours	-	8,162
CHP Power Generated, MWh/yr	0	39,415
Purchased Power, MWh/yr	43,500	4,085
Total Plant Fuel Use, MMBtu/yr	2,012,821	2,203,861
Btu Plant Fuel/Gal Ethanol	40,256	44,077
Average Central Station Generation Efficiency - Delivered, %	30.5%	30.5%
Central Station Fuel Use, Mbtu/yr	486,231	45,664
Total Fuel Use (Plant and Central Station), MMBtu/yr	2,499,051	2,249,525